

# (12) UK Patent Application (19) GB (11) 2 309 240 (13) A

(43) Date of A Publication 23.07.1997

(21) Application No 9603488.9

(22) Date of Filing 20.02.1996

(30) Priority Data

(31) 9601019

(32) 18.01.1996

(33) GB

(71) Applicant(s)

**Sofitech N.V.**

**(Incorporated in Belgium)**

**Rue de Stalle 142, B-1180 Brussels, Belgium**

(72) Inventor(s)

**Christopher Alan Sawdon**

**David Anthony Ballard**

(74) Agent and/or Address for Service

**Heseltine Lake & Co**

**Imperial House, 15-19 Kingsway, LONDON,**

**WC2B 6UD, United Kingdom**

(51) INT CL<sup>6</sup>

**C09K 7/06**

(52) UK CL (Edition O )

**E1F FGP**

(56) Documents Cited

**US 4012329 A**

**US 3878111 A**

(58) Field of Search

**UK CL (Edition O ) E1F FGP**

**INT CL<sup>6</sup> C09K**

**Online: WPI**

(54) Wellbore fluid

(57) A stable invert emulsion wellbore fluid in which the emulsified hydrophilic disperse phase has a water activity of less than 0.90 is characterised by the emulsifier which includes, in combination, a non-ionic alkoxylated surfactant and an anionic sulphonate surfactant. The wellbore fluid, which may be a brine-in-oil emulsion, is stable when the water exhibits a water activity below 0.90 but flips to produce a dispersion of the oil phase when the water activity is raised above 0.90.

GB 2 309 240 A

WELLBORE FLUID

This invention concerns wellbore fluids for use in the oil and gas exploration and production industries and embraces fluids used for drilling, completion, 5 workover or packing of wellbores. The invention is especially concerned with an emulsion wellbore fluid the continuous liquid phase of which consists of a water-immiscible oily liquid and in which the emulsifier comprises a combination of an alkoxylated 10 surfactant and an anionic sulphonate surfactant. This combination of agents has been found to provide stable oil continuous emulsions when the hydrophilic phase is of low water activity, and to allow the emulsion to destabilise or "flip" readily upon the addition of low 15 salinity water in a quantity sufficient to increase substantially the water activity of the water phase.

A wellbore is drilled by attaching to the bottom of a length of drill pipe a cutting bit which is rotated either by means of a prime mover on the surface 20 which applies rotary motion to the top end of the drill pipe or by means of a turbine motor being driven by circulating fluid in the wellbore.

In either case a drilling fluid is required to remove cuttings from around the bit and to transport 25 the cuttings to the surface for separation and removal. The drilling fluid also cools the bit and lubricates both bit and drill pipe thus reducing friction.

In many cases it is possible to use as the drilling fluid a simple mixture comprising water and a 30 smectite clay which increases the viscosity of the fluid for the purposes of suspending and transporting the cuttings. However it is often necessary to drill a wellbore through geological formations the constituent materials of which swell or disintegrate on contact 35 with water. In such cases an oil-based drilling fluid is used, that is a fluid in which the liquid phase consists of oil, or of water-in-oil emulsions which are

known in the art as "invert" emulsion fluids.

Such oil based drilling fluids avoid the hydration problems caused by water contacting shale or salt formations. They also possess advantages compared to  
5 water based fluids of enhanced lubrication of the drill pipe, and high stability at high temperatures.

Originally such oil based drilling fluids utilised diesel fuel or other similar petroleum fractions as the oil phase. However these contain relatively high  
10 proportions of aromatic hydrocarbons and other compounds which are toxic to marine life.

More recently, highly refined low aromatic mineral oils have been used. These are of much lower toxicity than diesel fuel. Various environmental authorities  
15 therefore permitted the discharge to the sea of cuttings contaminated with "low toxicity" mineral oil based drilling fluids.

However, in many offshore locations, this has caused the smothering of the sea bed with piles of  
20 cuttings in which the refined mineral oil has not biodegraded significantly, especially under the anaerobic conditions existing within a pile of cuttings.

This has led to increasingly stringent regulations  
25 on the concentration of mineral oils which may be discharged with the cuttings. Also the Paris Convention (Annex A, Part 1) is increasingly restricting the use in drilling fluids of "oils of a petroleum origin" whilst discharging cuttings to the  
30 sea.

Heretofore, prior art invert emulsion drilling fluids have generally utilised ionic emulsifiers, for example the calcium salts of fatty acids such as oleic acid, alkyl imidazolines, and alkylamidoamines and  
35 their derivatives. These provide stable water in oil emulsions at any salinity. Simple water washing of cuttings coated with such fluids results in increasing

quantities of the wash water being emulsified into the drilling fluid, causing an increase in viscosity of the drilling fluid to a sludge-like consistency, and very little dispersion of the oil in the wash water.

5       According to a first aspect of the present invention, there is provided a stable invert emulsion wellbore fluid in which the emulsified hydrophilic disperse phase has a water activity less than about 0.90, characterised in that the emulsifier comprises,  
10   in combination, a non-ionic alkoxyated surfactant and an anionic sulphonate surfactant.

It is surprising that the combination of a non-ionic alkoxyated surfactant and an anionic sulphonate surfactant yield a stable invert emulsion, because  
15   neither of these agents, when used alone, is capable of producing such an effect. It is also surprising that the stable invert emulsion of the invention will rapidly and completely destabilise and disperse by simple admixture with low salinity waters.

20       The wellbore fluid of the present invention allows a substantial reduction in the concentration of the oily phase on the cuttings which are discharged to the environment. This advantage is achieved because the wellbore fluid of this invention has the inherent  
25   property that the water immiscible component may be readily and near completely removed from the cuttings by a simple water washing process. This "washability" property is imparted to the wellbore fluid in accordance with the invention by utilising an  
30   emulsifier which is a combination of an alkoxyated non-ionic emulsifier and an anionic surfactant. This combination of components enables a stable brine-in-oil "invert" emulsion to be formed when the hydrophilic phase (or brine phase) exhibits a water activity ( $A_w$ )  
35   of below about 0.90, for example when the salt concentration of the brine phase is above about 10% w/w  $\text{CaCl}_2$ , or about 14.5% w/w  $\text{NaCl}$ . However, if the water

activity of the aqueous phase of the emulsion is raised above about 0.9, and preferably above 0.95, the invert emulsion rapidly destabilises and "flips" to produce a dispersion of the oil phase in the added water. This  
5 may be achieved by mixing the invert emulsion (for example coating the surface of a cutting) with a quantity of low salinity water (such as sea water or fresh water). This greatly enhances the ease of removal of the oily phase from cuttings.

10 Any water immiscible oily liquid may be used in the wellbore fluid of the invention so long as it is capable of forming an invert emulsion. Non-limiting examples of suitable oils are minerals oils, alpha olefins, modified vegetable oil derivatives.

15 The invert emulsion may be mixed with a low salinity water prior to disposal, or may be mixed with a low salinity water in the act of disposal, as for example by dumping the fluid into a body of water such as the sea.

20 Preferably, the alkoxyated non-ionic emulsifier exhibits an effective hydrophilic-lipophilic balance (HLB) no greater than 12, more preferably less than 10. Preferably the HLB is at least 6. The alkoxyated non-ionic emulsifier preferably has a cloud point of not  
25 greater than 30°C.

The non-ionic emulsifier preferably contains hydrophobic groups of not less than 10 carbon atoms, more preferably not less than 12 carbon atoms.

A mixture of alkoxyated non-ionic emulsifiers may  
30 be employed.

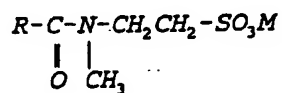
The alkoxyated non-ionic surfactants used in this invention are sometimes referred to as polyoxyalkylene surfactants. The number of alkylene oxide units in the or each of the polyoxyalkylene chain or chains of the  
35 surfactant is preferably in the range of from 1 to 10.

The alkylene oxide unit is very preferably an ethylene oxide, in which case it may be described as a

polyoxyethylene surfactant, but may alternatively be a propylene oxide unit. Surfactants in which the polyoxyalkylene chain is a combination of two different alkylene oxide units (for instance ethylene oxide and propylene oxide units) are also operable.

The non-ionic emulsifier may be selected from the group consisting of alcohol ethoxylates, alkylphenol ethoxylates, fatty acid esters of polyethylene glycols, ethoxylated sorbitan esters, non-ionic polyester surfactants containing poly (ethyleneoxide) groupings including partially or fully propoxylated variants of these molecules.

The anionic sulphonate surfactant used in the invention comprises a sulphonate group,  $-SO_3M$ , which may be attached directly to an alkyl, aryl or alkylaryl or alpha olefin hydrophobe, preferably containing between 10 and 22 carbon atoms. Alternatively, the hydrophobe may attached to the sulphonate group via an ester, amide or ether linkage. For example, sulphonates comprising an amide linkage separated from the sulphonate group by an ethylene moiety are preferred in the present invention; such compounds are known as taurates. One particular group of taurates are those having the following formula:



in which R is the  $C_{10}$  to  $C_{22}$  hydrophobe.

The total dose of emulsifiers present in the wellbore fluid is in the range of about 0.5% to about 10% by weight of the wellbore fluid.

Other additives which may be contained in the wellbore fluid include other surface active agents, viscosifiers such as organoclays and polymers, filtration control agents such as Gilsonite<sup>(TM)</sup> and organically modified lignite, density increasing agents (or weighting agents) such as powdered barytes or

hematite or calcium carbonate, or other wellbore fluid additives known to those skilled in the art.

The emulsified water phase of the wellbore fluid may contain dissolved salts such as alkali metal halides (for example sodium chloride), alkaline earth metal halides such as calcium chloride, or other water soluble organic compounds or salts for the purpose of adjusting the water activity of the dispersed liquid phase to less than about 0.90.

10        Preferably, the emulsified hydrophilic phase of the wellbore fluid is present from about 0.5% to 70% by volume of the wellbore fluid.

According to a second aspect of the present invention, there is provided a method of drilling a well, wherein the drilling fluid is a wellbore fluid according to the first aspect of this invention.

The cuttings generated in the drilling method of the invention are separated from the wellbore fluid and then washed with a wash water until the emulsion destabilises. Alternatively, the separated cuttings are dumped into or otherwise brought into contact with a body of water which will destabilise the emulsion. The wash water typically has a low salinity water phase, and thus may have a water activity greater than about 0.9, and preferably greater than about 0.95 (sea water has a water activity of between about 0.97 and 0.98). The washed cuttings may then be disposed of, substantially free from contaminating oil components.

30        The cuttings may be separated from the wellbore fluid by conventional means such as vibratory screens, hydrocyclones, and centrifuges. At this stage the separated cuttings will normally be coated with about 10-20% by weight of the wellbore fluid. The cuttings may then be passed to a secondary device in which they are washed with a low salinity water phase such as fresh water or sea water. The secondary device may,

for example, be a separate vibratory screen fitted with spray bars which provide multiple jets of water to impinge upon the bed of oily cuttings as it traverses the screen. By virtue of the rapid destabilisation of the adherent wellbore fluid on contact with the wash water, most of the superficial wellbore fluid is easily removed and passes through the screen, allowing cleaned cuttings to be discharged. This discharge may be to the sea in offshore drilling, or the cuttings may be spread over the surface of the ground ("land farmed") in onshore operations. In either case, the reduction in concentration of the oily phase allows much more rapid biodegradation of the oil, and improved recovery of the sea bed or the land to a clean natural ecosystem. Using the invention, it is possible to remove about 90% of the oil by the water washing process resulting in about a ten fold reduction in the organic loading of the discharged cuttings.

The wash water may optionally contain other additives or salts such as potassium chloride, to minimise the break-up of cuttings on contact with water. The wash water is, however, preferably of water activity greater than 0.95. Other optional additives to the wash water may include coagulants to allow more ready separation of the oil, water, and solids from the used wash water, or small amounts of detergents to enhance the washing process.

After washing the cuttings, the wash water will contain a dispersion of the oil and solid phases of the wellbore fluid, plus some of the smaller cuttings which may have passed through the screen. Most of the solids and the oil may be separated from the wash water by, for example, centrifugation. The fine solids are discharged similarly to the cuttings, and the oil phase is returned to the wellbore fluid. The wash water, substantially free of oil may be discharged immediately to the environment, or preferably recycled to the



washing process. Ultimately on repeated recycling, the wash water will accumulate a level of salts or other Water Activity lowering agent from the wellbore fluid sufficient to lower the water activity to a point where the washing becomes less effective. At this stage the wash water may be replenished with a fresh supply.

An option when drilling offshore is to discharge the cuttings, coated with the wellbore fluid of this invention, direct to the sea without prior washing. On contact with sea water, much of the wellbore fluid will wash off and disperse into the sea prior to the cuttings sedimenting onto the sea bed. This is in contrast to conventional oil based muds which will not disperse on contact with sea water, leading to high organic loadings on the sea bed.

According to a third aspect of the present invention, there is provided the use, for the completion, workover or packing of a wellbore, of a stable invert emulsion wellbore fluid in which the emulsified hydrophilic disperse phase has a water activity less than about 0.90, characterised in that the emulsifier comprises, in combination, a non-ionic alkoxylated surfactant and an anionic sulphonate surfactant.

According to a fourth aspect of the present invention, there is provided a method of drilling a well, wherein the drilling fluid is a brine-in-oil emulsion that is stable if the water exhibits a water activity below 0.90 but flips to produce a dispersion of the oil phase when the water activity is raised above 0.90. This aspect of the invention also encompasses a wellbore fluid which is a brine-in-oil emulsion that is stable if the water exhibits a water activity below 0.90 but flips to produce a dispersion of the oil phase when the water activity is raised above 0.90. The wellbore fluid may also be used in the completion, workover or packing of a wellbore.

The invention will now be illustrated by reference to the following examples.

In these examples, the wellbore fluid properties were tested in accordance with API RP 13B-2 1990.

5 The following abbreviations are used:

ES Electrical Stability of an emulsion (volts).  
A high number implies a high emulsion stability.

HTHP FL High Temperature and High Pressure Fluid  
10 Loss. A measure of the ease of filtering a drilling fluid through a filter paper under HTHP conditions. Results in millilitres of filtrate. Low filtrate volumes are generally regarded as advantageous.

15 **Example 1 (comparative)**

A drilling fluid which produced an unstable emulsion was prepared by mixing the following in order on a Hamilton Beach blender. This formulation corresponds to a drilling fluid with a water activity  
20 of 0.85 and an oil:water ratio of 60:40.

158.6 mls	Clairsol 350 MHF
10 g	Alcohol ethoxylate (cetyl/stearyl alkyl group, 5 moles ethylene oxide)
1 g	Lime
4 g	VISTONE
25 2 g	INTERDRILL S
1 g	TRUFLO 100
27.4 g	Sodium Chloride
114.3 mls	Water
220.1 g	Barite

30 Clairsol 350 MHF is a mineral oil, VISTONE is an organoclay viscosifier, and INTERDRILL S and TRUFLO 100 are fluid loss additives.

The fluid after mixing, before hot rolling had an  
35 ES of 92 volts.

After ageing the solids in the fluid had dropped to the bottom of the ageing cell and were water wet. This shows that the emulsion had been destroyed by the hot rolling process which is an unacceptable  
5 characteristic for an oil based fluid. It is standard practice to re-stir the sample for five minutes on a Hamilton Beach blender after hot rolling. After stirring the ES was 100 and the HTHP FL was 25 ml.

This experiment demonstrates that, used on its  
10 own, the alcohol ethoxylate does not provide enough emulsion stability to be used in a drilling fluid.

**Example 2 (comparative)**

A drilling fluid which produced an unstable direct emulsion was prepared by mixing the following in order  
15 on a Hamilton Beach blender. This formulation corresponds to a drilling fluid with a water activity of 0.85 and an oil:water ratio of 60:40.

158.6 mls	Clairsol 350 MHF
10 g	Alkyl sulphonate (sodium C <sub>14/16</sub> alpha olefin sulphonate)
1 g	Lime
4 g	VISTONE
2 g	INTERDRILL S
1 g	TRUFLO 100
27.4 g	Sodium Chloride
114.3 mls	Water
220.1 g	Barite

The ES measured at 49°C (120°F) before hot rolling was 0. After hot rolling the above system for 16 hours  
30 at 121°C (250°F) the ES remained at 0.

This experiment demonstrates that, used on its own, the sodium alkene sulphonate does not provide enough emulsion stability to be used in a drilling fluid.

35 **Example 3 (comparativ )**

A drilling fluid which produced an unstable direct emulsion was prepared by mixing the following in order on a Hamilton Beach blender. This formulation corresponds to a drilling fluid with a water activity of 0.85 and an oil:water ratio of 60:40.

158.6 mls	Clairsol 350 MHF
10 g	Alkyl taurate (sodium N-methyl N-oleoyl taurate)
1 g	Lime
4 g	VISTONE
2 g	INTERDRILL S
1 g	TRUFLO 100
27.4 g	Sodium Chloride
114.3 mls	Water
220.1 g	Barite

The ES measured at 49°C (120°F) before hot rolling was 0. After hot rolling the above system for 16 hours at 121°C (250°F) the ES remained at 0.

This experiment demonstrates that, used on its own, sodium alkene taurate does not provide enough emulsion stability to be used in a drilling fluid.

#### Example 4

A drilling fluid in accordance with the invention, which produced a stable invert emulsion, was prepared by mixing the following in order on a Hamilton Beach blender. This formulation corresponds to a drilling fluid with a water activity of 0.85 and an oil:water ratio of 60:40. The emulsifier is a combination of the components shown to be ineffective when used alone in Examples 1 and 2.

158.6 mls	Clairsol 350 MHF
8 g	Alcohol ethoxylate (cetyl/stearyl alkyl group, 5 moles ethylene oxide)
2 g	Alkyl sulphonate (sodium C <sub>14/16</sub> alpha olefin sulphonate)
1 g	Lime
4 g	VISTONE
2 g	INTERDRILL S
1 g	TRUFLO 100
27.4 g	Sodium Chloride
114.3 mls	Water
220.1 g	Barite

The fluid had an ES after mixing of 263 volts. After hot rolling the above system for 16 hours at 121°C (250°F) the fluid had an ES of 466 volts and an HTHP FL of 5 ml.

Surprisingly this fluid demonstrates that very acceptable invert emulsion stability for drilling purposes can be provided by a combination of an alkyl sulphonate and an alcohol ethoxylate neither of which provides a stable invert emulsion when used alone.

#### Example 5

A drilling fluid in accordance with the invention, which produced an stable invert emulsion, was prepared by mixing the following in order on a Hamilton Beach blender. This formulation corresponds to a drilling fluid with a water activity of 0.85 and an oil:water ratio of 60:40. The emulsifier is a combination of the components shown to be ineffective when used alone in Examples 1 and 3.

	158.6 mls	Clairsol 350 MHF
	8 g	Alcohol ethoxylate (cetyl/stearyl alkyl group, 5 moles ethylene oxide)
	2 g	Alkyl taurate (sodium N-methyl N-oleoyl taurate)
	1 g	Lime
5	4 g	VISTONE
	2 g	INTERDRILL S
	1 g	TRUFLO 100
	27.4 g	Sodium Chloride
	114.3 mls	Water
10	220.1 g	Barite

The fluid after mixing had an ES of 397. After hot rolling the above system for 16 hours at 121°C (250°F) the fluid had an ES of 487 volts and an HTHP FL of 3.0 ml.

This experiment demonstrates that there is a very significant improvement in the emulsion stability (increase in ES and a reduction in HTHP FL) by the use of an alkyl taurate in combination with an alcohol ethoxylate, neither of which are effective alone.

#### Example 6 (comparative)

A drilling fluid which produced an unstable direct emulsion was produced by mixing the following in order on a Hamilton Beach blender. This formulation corresponds to a drilling fluid with a water activity of 1.0 and an oil:water ratio of 60:40.

161.3 mls	Clairsol 350 MHF
8 g	Alcohol ethoxylate (cetyl/stearyl alkyl group, 5 moles ethylene oxide)
2 g	Alkyl sulphonate (sodium C <sub>14/16</sub> alpha olefin sulphonate)
1 g	Lime
4 g	VISTONE
2 g	INTERDRILL S
1 g	TRUFLO 100
116.1 mls	Water
242.7 g	Barite

5  
10 The ES measured at 49°C (120°F) before hot rolling was 0. After hot rolling the above system for 16 hours at 121°C (250°F) the ES remained at 0.

15 This experiment demonstrates that when the alcohol ethoxylate and sodium alkene sulphonate are exposed to conditions of low salinity water phase they do not form invert emulsions but form a direct emulsion i.e. they destabilise.

#### Example 7

20 A drilling fluid in accordance with the invention which produced a stable emulsion was produced by mixing the following in order on a Hamilton Beach blender. This formulation corresponds to a drilling fluid with a water activity of 0.85 and an oil:water ratio of 60:40.  
25 It is hereafter referred to as "new mud".

	157.0 mls	Clairsol 350 MHF
	8 g	Alcohol ethoxylate (cetyl/stearyl alkyl group, 5 moles ethylene oxide)
	2 g	Alkyl sulphonate (Sodium C <sub>14/16</sub> alpha olefin sulphonate)
	1 g	Lime
5	4 g	VISTONE
	0.9g	Secondary Viscosifier
	2 g	INTERDRILL S
	1 g	TRUFLO 100
	27.5 g	Sodium Chloride
10	114.3 mls	Water
	220.9 g	Barite

A drilling fluid was also prepared using conventional emulsifiers, so a comparative study of washing characteristics could be made. The following were mixed in order on a Hamilton Beach blender. This formulation corresponds to a drilling fluid with a water activity of 0.85 and an oil:water ratio of 60:40.

	158.3 mls	Clairsol 350 MHF
20	10 g	INTERDRILL EMUL HT (emulsifier)
	2 g	INTERDRILL LO-RM (rheology modifier)
	1 g	Lime
	4 g	VISTONE
	2 g	INTERDRILL S
25	1 g	TRUFLO 100
	32.18 g	Calcium Chloride (83.5% purity)
	110.8 mls	Water
	220.9 g	Barite

Two 25 g samples of limestone with a particle size greater than 2 mm and less than 4 mm were presaturated with sea water containing 29.5 g/l sodium chloride to represent cuttings drilled from a well. One limestone



sample was mixed in the new mud, and the other in the conventional mud under the same conditions, to ensure thorough coating of the cuttings by each fluid. The contaminated samples of limestone were then removed  
5 from each fluid and washed separately, by gentle agitation in 300 ml of fresh water for 1 minute. The samples of limestone were separated from the water. Analysis of the level of oil contamination was performed for both samples before and after the washing  
10 process.

The results were as follows:

	Oil Concentration (g oil/kg cuttings)	
	Invention	Comparative
15 Before Washing	50.8	64.9
After Washing	14.8	46.4

The oil and solids dispersed in the water used for washing were then recovered by centrifuging the water for two minutes at 3000 rpm.

20 This experiment demonstrates the enhanced washing characteristics of the fluid containing alcohol ethoxylate and alkyl sulphonate compared to the conventional fluid, and also the process of washing cuttings contaminated with this fluid to readily  
25 achieve low levels of retained oil contamination.

CLAIMS:

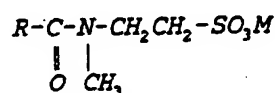
1. A stable invert emulsion wellbore fluid in which the emulsified hydrophilic disperse phase has a water activity less than about 0.90, characterised in  
5 that the emulsifier comprises, in combination, a non-ionic alkoxyated surfactant and an anionic sulphonate surfactant.
2. A wellbore fluid according to claim 1, wherein the alkoxyated non-ionic emulsifier exhibits  
10 an effective hydrophilic-lypophilic balance (HLB) no greater than about 12.
3. A wellbore fluid according to claim 2, wherein the alkoxyated non-ionic emulsifier exhibits an effective hydrophilic-lypophilic balance (HLB) of at  
15 least 6.
4. A wellbore fluid according to claim 1, 2 or 3, wherein the alkoxyated non-ionic emulsifier exhibits a cloud point of not greater than 30°C.
5. A wellbore fluid according to any preceding  
20 claim, wherein the emulsifier contains hydrophobic groups of not less than 10 carbon atoms.
6. A wellbore fluid according to any preceding claim, wherein the total dose of emulsifiers present in the wellbore fluid is in the range of about 0.5% to  
25 about 10% by weight of the wellbore fluid.
7. A wellbore fluid according to any preceding claim, wherein the number of alkylene oxide units in the or each of the polyoxyalkylene chain or chains of the surfactant is in the range 1 to 10.
- 30 8. A wellbore fluid according to any preceding claim, wherein the alkoxyated non-ionic surfactant is an ethoxyated non-ionic surfactant.
9. A wellbore fluid according to any preceding claim, wherein the anionic sulphonate surfactant  
35 comprises a sulphonate group,  $-SO_3M$ , attached directly to an alkyl, aryl or alkylaryl or alpha olefin hydrophobe.

10. A wellbore fluid according to claim 9, wherein the hydrophobe contains between 10 and 22 carbon atoms.

11. A wellbore fluid according to any preceding claim, wherein the anionic sulphonate surfactant comprises a sulphonate group,  $-SO_3M$ , attached to an alkyl, aryl or alkylaryl or alpha olefin hydrophobe via an ester, amide or ether linkage.

12. A wellbore fluid according to claim 11, wherein the anionic surfactant is a taurate.

13. A wellbore fluid according to claim 12, wherein the anionic surfactant has the following formula:



in which R is an alkyl, aryl, alkylaryl or alpha olefin hydrophobe containing 10 to 22 carbon atoms.

14. A wellbore fluid according to any preceding claim, wherein the emulsified hydrophilic phase of the wellbore fluid is present from about 0.5% to 70% by volume of the wellbore fluid.

15. A method of drilling a well, wherein the drilling fluid is a wellbore fluid as claimed in any one of claims 1 to 14.

16. A method according to claim 15, wherein the cuttings generated during drilling are separated from the wellbore fluid and washed with a wash water until the emulsion destabilises.

17. A method according to claim 15, wherein the cuttings generated during drilling are separated from the wellbore fluid and the cuttings dumped into or otherwise brought into contact with a body of water which will destabilise the emulsion.

18. A method according to claim 16 or 17, wherein the wash water has a low salinity water phase.

19. The use, for the completion, workover or

packing of a wellbore, of a stable invert emulsion wellbore fluid in which the emulsified hydrophilic disperse phase has a water activity less than about 0.90, characterised in that the emulsifier comprises,  
5 in combination, a non-ionic alkoxylated surfactant and an anionic sulphonate surfactant.

20. A method of drilling a well, wherein the drilling fluid is a brine-in-oil emulsion that is stable if the water exhibits a water activity below  
10 0.90 but flips to produce a dispersion of the oil phase when the water activity is raised above 0.90.

21. A wellbore fluid which is a brine-in-oil emulsion that is stable if the water exhibits a water activity below 0.90 but flips to produce a dispersion  
15 of the oil phase when the water activity is raised above 0.90.

22. The use, for the completion, workover or packing of a wellbore in accordance with claim 21.

23. A wellbore fluid substantially as  
20 hereinbefore described, with reference to the accompanying examples.



The  
Patent  
Office

20

Application No: GB 9603488.9  
Claims searched: 1 to 19 & 23

Examiner: D.B. Pepper  
Date of search: 13 February 1997

**Patents Act 1977**  
**Search Report under Section 17**

**Databases searched:**

UK Patent Office collections, including GB, EP, WO & US patent specifications, in:

UK Cl (Ed.O): E1F FGP.

Int Cl (Ed.6): C09K 7/02D, 7/02D4, 7/06, 7/06D.

Other: Online: WPI

**Documents considered to be relevant:**

Category	Identity of document and relevant passage	Relevant to claims
A	US 4012329 A (Hayes et al)	-
A	US 3878111 A (McGlothlin et al)	-

X Document indicating lack of novelty or inventive step  
Y Document indicating lack of inventive step if combined with one or more other documents of same category.  
& Member of the same patent family

A Document indicating technological background and/or state of the art.  
P Document published on or after the declared priority date but before the filing date of this invention.  
E Patent document published on or after, but with priority date earlier than, the filing date of this application.